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Flue Gas Desulfurization Costs for Large Coal-Fired Boilers (Draft)

PEDCo-Environmental, Inc.
Cincinnati, OH

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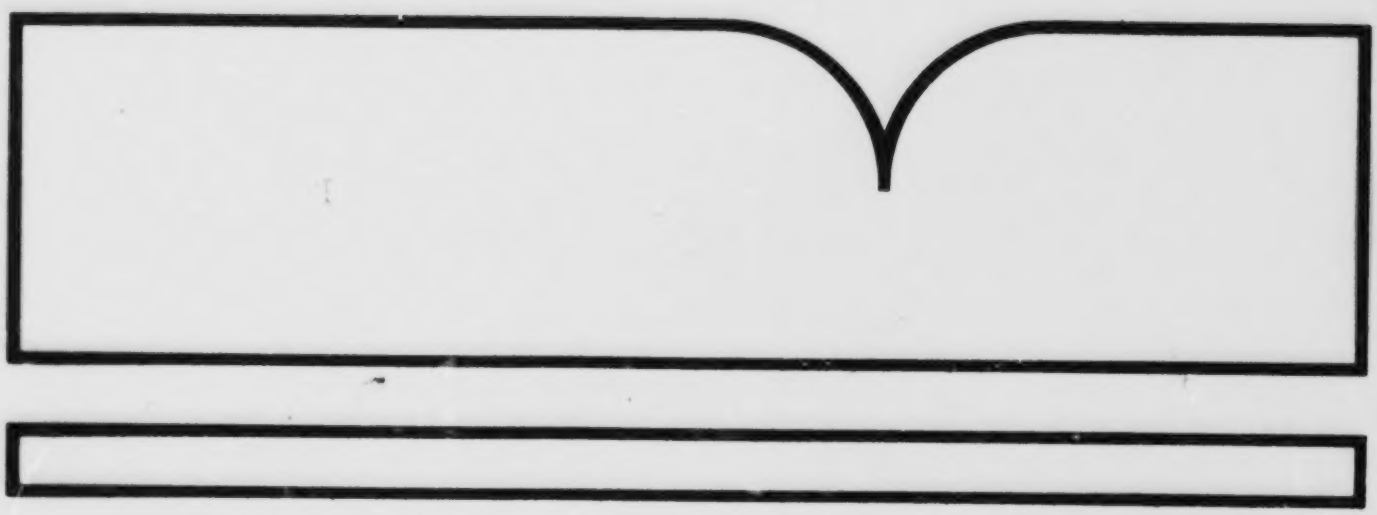

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FLUE GAS DESULFURIZATION COSTS FOR LARGE COAL-FIRED BOILERS

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Contract No. 68-02-2842
Task No. 16

Project Officer, Richard E. Jenkins

Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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In support of a program to review New Source Performance Standards for sulfur dioxide emissions from coal-fired steam generators, the U.S. Environmental Protection Agency is preparing estimates of the costs of flue gas desulfurization (FGD) systems. The program is designed to determine the costs of FGD at various efficiencies, regulation levels, and coal sulfur levels with particular emphasis on the cost impacts of averaging time. EPA has contracted with PEDCo Environmental, Inc. to develop costs of lime FGD systems for alternate regulation levels and coal sulfur levels. Model steam-electric generating plants were used as a basis for estimating these costs.

In section 2 the methodology and assumptions used in the analysis are presented. Section 3 presents the results of the study.

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1.0 INTRODUCTION

In support of a program to review New Source Performance Standards for sulfur dioxide emissions from coal-fired steam generators, the U.S. Environmental Protection Agency is preparing estimates of the costs of flue gas desulfurization (FGD) systems. The program is designed to determine the costs of FGD at various efficiencies, regulation levels, and coal sulfur levels with particular emphasis on the cost impacts of averaging time. EPA has contracted with PEDCo Environmental, Inc. to develop costs of lime FGD systems for alternate regulation levels and coal sulfur levels. Model steam-electric generating plants were used as a basis for estimating these costs.

In Section 2 the methodology and assumptions used in the analysis are presented. Section 3 presents the results of the study.

2.0 METHODOLOGY AND APPROACH FOR ESTIMATING FLUE GAS DESULFURIZATION COSTS

The capital and annualized costs of flue gas desulfurization (FGD) systems can vary depending on several factors. Factors of major cost impact are boiler size and capacity factor; type of FGD system; sulfur content and heating value of the coal; maximum allowable SO_2 emission rate; boiler status (new or retrofit installation); replacement power requirements and byproduct disposal requirements.

To present unencumbered cost estimates and illustrate the impact of site and process factors on total capital and annualized costs of FGD systems, a model plant approach was used. The following sections define the model plants and the cost methodology.

2.1 COST ELEMENTS

The capital cost of an FGD system is composed of direct and indirect costs incurred up to the successful commissioning date of the facility. Direct costs include the cost of various equipment items and the labor and material required for installing the equipment items and interconnecting the system. Indirect costs are costs that are necessary for the overall facility but cannot be attributed to a specific

equipment item. Indirect costs include such items as freight, spares, interest, taxes, etc.

Operating costs of a facility include labor, raw materials, and utilities required to operate the system on a day-to-day basis. These costs include such items as electricity, water, operating labor, etc.

A brief description of the capital and annual operating cost components and the procedure used to obtain their values is presented in this section.

2.1.1 Capital Costs

A discussion of capital costs for FGD systems follows under the headings "Direct Costs" and "Indirect Costs."

Direct Costs

The "bought-out" cost of the equipment and the cost of installing it are considered direct costs. Installation costs also include the interconnection of the system, which involves piping, electrical, and other work for commissioning the system. Installation of the equipment includes foundations, supporting structures, enclosures, piping, ducting, control panels, instrumentation, insulation, painting and other similar items. Costs for interconnection of the equipment involve site development, construction of access roads and walkways, and the establishment of rail, barge, or truck facilities. The cost of administrative

facilities is also considered as a part of the direct costs.

Various procedures for estimating the direct costs are available, each using a different route to obtain an installed cost of a facility. In this study, the installation-factor technique is used to estimate total direct costs.

The bought-out cost of each equipment item is multiplied by an individual installation factor to obtain the installed cost. This installed cost also includes the proportional cost of interconnecting the equipment into the system. The installation factors are based on the complexity of the equipment and the cost of the material and labor required. The installed costs of all the equipment are added together to obtain the total direct cost of the facility.

Direct capital costs for an FGD system include the purchase and installation of equipment including absorbers, fans and motors, reheaters, soot blowers, pumps, tanks, agitators, raw material preparation and storage equipment byproduct dewatering equipment, sludge disposal or byproduct recovery facilities, foundations, and support. The components vary depending on the type of absorbent used in the system.

Indirect Costs

The indirect costs of FGD systems include the following:

Interest accrued during construction on borrowed capital.

Engineering costs: includes administrative, process, project, and general; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; purchasing; procurement; travel expenses; living expenses; expediting; inspection; safety; communications; modeling; pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services.

Field overhead: includes the cost of securing permits, and right-of-way sections, and the cost of insurance for the equipment and personnel on site.

Freight: includes delivery costs on process and related equipment shipped f.o.b. point of origin.

Off-site expenditures: includes those for powerhouse modifications; interruption to power generation; and service facilities added to the existing plant facilities.

Taxes: includes sales, franchise, property, and excise taxes.

Spare parts: (stocked to permit high process availability): includes pumps, valves, controls, special piping and fittings, instruments, and similar items.

Shakedown: includes the costs associated with the system start-up.

Contractor's fee and expenses: includes costs for field labor payroll; supervision field office; administrative personnel; construction offices; temporary roadways; railroad trackage; maintenance and welding shops; parking lot; communications; temporary piping and electrical and sanitary facilities; rental equipment; unloading and storage of materials; travel expenses; permits; licenses; taxes; insurance; overhead; legal

liabilities; field-testing of equipment; start-up; labor relations.

Contingency costs: includes those resulting from malfunctions, equipment design alterations, and similar unforeseen sources.

Land cost: includes only the cost of the land required for sludge disposal. The cost of land for installing equipment items is accounted for in the installation factors.

All the indirect cost components, except the land cost, are estimated by multiplying the direct costs by an indirect cost factor; the land cost is based on land rate and the disposal area required.

2.1.2 Annual Operating Costs

Generally calculated on an annual basis, the operating costs of an FGD system are comprised of:

Utilities: includes water for slurries, cooling, and process use; electricity for pumps, fans, valves, lighting, and controls; and fuel or steam for reheat if required.

Operating labor: includes supervision and the skilled and unskilled labor required to operate, monitor and control the system.

Maintenance and repairs: consists of both manpower and materials to keep the units operating efficiently. The function of maintenance is both preventive and corrective, to keep outages to a minimum.

Overhead: represents a business expense that is not charged directly to a particular part of a process but is allocated to it. Overhead costs include administrative, safety, engineering, legal, and medical services; payroll; employee benefits; recreation; and public relations.

2.1.3 Annual Revenue Requirements

The capital investment of a pollution control system is generally translated into annual fixed charges. These charges, along with the annual operating costs, represent the total revenue requirement of an FGD system.

The annual fixed charges are classified under four cost components: depreciation, taxes, insurance, and capital costs. The component costs are as follows:

Depreciation: The value of the depreciation component is obtained by using a straight-line depreciation over the life period of the pollution control system. A 15-year life is assumed for depreciation purposes. The annual cost is calculated by dividing the total capital investment by the assumed years of life.

Taxes: The value of the tax component is calculated by multiplying the total capital cost by the input tax rate. The tax rate varies for different plants.

Insurance: The value of the insurance component is obtained by multiplying the total capital cost by the insurance rate for the pollution control system. A constant insurance rate of 0.3 percent is assumed.

Capital charges: The value of capital charges represent the interest paid per year for the usage of capital. The value of this component depends on the applicable rate of interest for the borrowed capital. The value is obtained by multiplying the total capital cost by the input interest rate.

The total annual fixed changes are obtained by adding the values of the above four components. The total annual revenue required can then be obtained by adding the annual operating costs to the total annual fixed charges.

2.2 COST ESTIMATING APPROACH

A model plant approach was used in estimating the costs of FGD on new coal-fired boilers. Typical plants were defined with characteristics intended to be representative of the electric utility industry. Characteristics of the model plants are presented in Table 2-1. Analyses of the coals used in the calculation of costs are given in Table 2-2.

The model plants were selected to incorporate three varying cost factors: coal analysis, degree of SO_2 control required, and averaging time over which the regulation must be met.

Eleven regulation levels were examined in the analysis in order to determine the economic effects various regulatory levels for SO_2 emissions for coal-fired utility boilers. Table 2-3 lists the regulation levels examined.

Other important considerations in control system costs are redundancy in the control system and the averaging time over which a particular emission level must be attained. For purposes of this study, the FGD systems were assumed to require a single spare module including pumps, tanks, and associated equipment.

The specific time period over which emission test results are averaged to determine compliance has a significant impact on the selection and design of the control

Table 2-1. MODEL PLANT PARAMETERS AND ASSUMPTIONS USED IN THE FGD ANALYSIS

Model plant parameters	Characteristics and assumptions				
Plant capacities, MW	500 (single boilers)				
Plant status	New				
Coal characteristics	(See Table 2-2)				
Location	Midwest location - East North Central Region				
Boiler data					
Capacity factor	Assumed 0.65 for all plants				
	Capacity, MW	Heat rate[1], joules/kWh (Btu/kWh)		Flue gas[1] flow rate, m^3/sec/MW (acfm/MW)	Remaining life, yr
Heat rates, flue gas flow rates,	500	9,400	(9,000)	1.45 (3,080)	35
Flue gas temperature	Assumed 155°C (310°F)				
Operating cost factors					
Raw materials[2]					
Lime cost	$40.20/ton				
Electricity cost	25 mills/kWh				
Capital recovery	18.75 percent of total capital investment				
Taxes and insurance	4 percent of total capital investment				
Sludge disposal	On-site disposal of stabilized sludge				
Redundancy requirements					
500 MW	1 spare module				

[1] Detailed Cost Estimates for Advanced Effluent Desulfurization Processes, prepared for Control Systems Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, under Interagency Agreement EPA IAG-134(d) Part A, by G.C. McGlamery, et al., Tennessee Valley Authority, pp. 60, 66. May 1974.

[2] Costs were obtained from distributors of the various products and escalated to August 1980 dollars.

Table 2-2. SULFUR LEVELS OF COALS EXAMINED IN THE COST ANALYSIS

Coal type	Sulfur content (long term average), lbs $S/10^6$ Btu
Eastern bituminous	3.33
Eastern bituminous	2.50
Eastern bituminous	1.67
Eastern bituminous	0.83
Western subbituminous	0.60
Western subbituminous	0.40

Table 2-3. REGULATION LEVELS EXAMINED

Emission limitation lb $SO_2/10^6$ Btu heat input
0.20
0.33
0.50
0.67
0.80
1.20
1.67
3.33
5.00
6.77
85% control

process. This especially true in the case of SO_2 emission limitations. Coal is inherently variable when looking at the sulfur content. The sulfur occurs in veins as pyrites thus producing a nonhomogeneous condition when sulfur content is considered. This variability in sulfur content is very significant when looking at shorter averaging times over which a regulation must be met. The effect of shorter averaging times is an increase in the maximum sulfur content for which an FGD system must be designed.

For this cost study, three regulatory averaging times were examined. In Case 1, the maximum annual average sulfur content was used as a design basis. In Case 2, it was assumed that the regulation must be met 90 percent of the time over a monthly period (3 days of excursions per month). The maximum sulfur content used as the design basis for this case were two relative standard deviations (RSD's) higher in sulfur than the long term average. In Case 3, it was assumed that the regulation must be met continuously. The maximum design sulfur content for this case were three RSD's above the long term average sulfur content. Basic to the study was the assumption that regardless of long-term sulfur level, one RSD for any coal would be 0.15 (times the sulfur content).

The design parameters used for FGD systems in the analysis are presented in Table 2-4. The parameters were

Table 2-4. DESIGN PARAMETERS FOR THE LIME FGD SYSTEM

Model plant parameters for 85% control	Characteristics and assumptions
FGD system	Lime
Absorber type	TCA
Number of stages	3
Liquid to gas ratio, L/G l/m^3 (gal/1000 acf)	8.0 (60)
Gas velocity in absorber, m/sec (ft/sec)	3.0 (10)
Flue gas temperature at absorber outlet, °C (°F)	52 (125)
Degree of reheat, °C (°F)	28 (50)
Hold tank retention time, min	10

developed based on review of existing FGD installations and by contacts with the manufacturers of the various FGD systems.

Another factor considered in the study was partial scrubbing of the boiler flue gases. For regulatory control cases where less than 69 percent SO_2 removal was required, it was assumed that only a portion of the gas would be scrubbed at 85 percent SO_2 removal with the remaining portion of the flue gas bypassing the scrubber. The reheat requirement was also reduced for these cases to account for the heat of the bypassed gas stream.

3.0 MODEL PLANT COSTS

The matrix of cost cases estimated for this analysis is presented in Table 3-1. Not all cases on the matrix were possible to cost and such were excluded. The criteria for exclusion was a case where the required SO_2 removal efficiency was greater than 85 percent or a case where the coal has an emission potential at or below the required emission limit.

In Case 1, the costs for a lime FGD system were estimated assuming the regulation must be net over an annual averaging period. Table 3-2 presents the capital costs in dollars per kW of net capacity for Case 1. The annual operation and maintenance costs in mills/kWh are presented in Table 3-3. The fixed annual charges in mills/kWh are presented in Table 3-4. The energy penalty in percent of net plant output (500 MW) is presented in Table 3-5. Capacity penalties in percent of plant net energy production are presented in Table 3-6.

For Case 2, the costs were estimated assuming the regulation required compliance 90 percent of the time on a monthly basis with 3 days of excursions allowed per month.

Table 3-1 COST CASES ANALYZED.

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2						
0.33						
0.50						
0.67						
0.80						
1.2						
1.67						
3.33						
5.00						
6.67						
85% control						

* Indicates partial scrubbing.

Table 3-2 CAPITAL COSTS IN $/kW FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON LONG TERM SULFUR CONTENT.

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	110.56	NA	NA	NA	NA	NA
0.33	109.34	112.64	NA	NA	NA	NA
0.50	*35.93	111.25	114.59	NA	NA	NA
0.67	*17.59	*57.19	113.38	122.86	NA	NA
0.80	NA	*34.33	*65.01	122.21	NA	NA
1.2	NA	NA	*31.77	120.08	127.78	NA
1.67	NA	NA	NA	*68.34	125.65	132.42
3.33	NA	NA	NA	NA	*40.82	*75.41
5.00	NA	NA	NA	NA	NA	*35.55
6.67	NA	NA	NA	NA	NA	NA
85% control	111.25	113.76	116.26	123.71	129.72	135.02

* Indicates partial scrubbing.

Table 3-3 ANNUAL OPERATION AND MAINTENANCE COSTS IN MILLS/kWh FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON LONG TERM SULFUR CONTENT

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	1.83	NA	NA	NA	NA	NA
0.33	1.78	1.94	NA	NA	NA	NA
0.50	*0.72	1.87	2.05	NA	NA	NA
0.67	*0.44	*1.08	1.98	2.61	NA	NA
0.80	NA	*0.72	*1.28	2.56	NA	NA
1.2	NA	NA	*0.69	2.41	3.00	NA
1.67	NA	NA	NA	*1.51	2.87	3.41
3.33	NA	NA	NA	NA	*1.02	*2.00
5.00	NA	NA	NA	NA	NA	*0.95
6.67	NA	NA	NA	NA	NA	NA
85% control	1.87	2.00	2.15	2.67	3.17	3.66

* indicates partial scrubbing

Table 3-4 FIXED ANNUAL COSTS IN mills/kWh FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON LONG TERM SULFUR AVAILABILITY.

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.41	NA	NA	NA	NA	NA
0.33	3.38	3.48	NA	NA	NA	NA
0.50	*1.11	3.43	3.54	NA	NA	NA
0.67	*0.54	*1.77	3.50	3.79	NA	NA
0.80	NA	*1.06	*2.01	3.77	NA	NA
1.2	NA	NA	*0.98	3.71	3.95	NA
1.67	NA	NA	NA	*2.11	3.88	4.09
3.33	NA	NA	NA	NA	*1.26	*2.33
5.00	NA	NA	NA	NA	NA	*1.10
6.67	NA	NA	NA	NA	NA	NA
85% control	3.43	3.52	3.59	3.82	4.01	4.17

* Indicates partial scrubbing.

Table 3-5 ENERGY PENALTY EXPRESSED AS PERCENT OF NET PLANT OUTPUT FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON LONG TERM SULFUR CONTENT

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	5.39	NA	NA	NA	NA	NA
0.33	5.39	5.39	NA	NA	NA	NA
0.50	*1.42	5.39	5.39	NA	NA	NA
0.67	*0.41	*1.68	5.39	5.39	NA	NA
0.80	NA	*1.26	*2.63	5.39	NA	NA
1.2	NA	NA	*1.06	5.39	5.39	NA
1.67	NA	NA	NA	*2.54	5.39	5.39
3.33	NA	NA	NA	NA	*1.26	*2.54
5.00	NA	NA	NA	NA	NA	*0.94
6.67	NA	NA	NA	NA	NA	NA
85% control	5.39	5.39	5.39	5.39	5.39	5.39

* indicates partial scrubbing

Table 3-6 CAPACITY PENALTY EXPRESSED AS PERCENT OF NET PLANT OUTPUT FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON LONG TERM SULFUR CONTENT

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term averaged), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.34	NA	NA	NA	NA	NA
0.33	3.34	3.34	NA	NA	NA	NA
0.50	*0.88	3.34	3.34	NA	NA	NA
0.67	*0.25	*1.39	3.34	3.34	NA	NA
0.80	NA	*0.78	*1.63	3.34	NA	NA
1.2	NA	NA	*0.66	3.34	3.34	NA
1.67	NA	NA	NA	*1.58	3.34	3.34
3.33	NA	NA	NA	NA	*0.78	*1.58
5.00	NA	NA	NA	NA	NA	*0.58
6.67	NA	NA	NA	NA	NA	NA
85% control	3.34	3.34	3.34	3.34	3.34	3.34

* indicates partial scrubbing

It was assumed to meet this requirement that the scrubbers would be designed for two RSD's (30%) above the long term average sulfur content. Capital costs are presented in Table 3-7. Annual operation and maintenance costs are presented in Table 3-8. Fixed annual charges are presented in Table 3-9. Energy and capacity penalties are presented in Tables 3-10 and 3-11, respectively.

In Case 3, the costs were estimated assuming the regulation must be met at all times (no excursions). It was assumed that designing the FGD system for three RSD's (45%) above the long-term average sulfur content would meet this requirement. Capital costs for this case are presented in Table 3-12. Annual operation and maintenance costs are presented in Table 3-13 with annual fixed costs in Table 3-14. Energy and capacity penalties are presented in Tables 3-15 and 3-16, respectively.

Table 3-7 CAPITAL COSTS IN $/kW FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 2 RSD SULFUR VARIABILITY (ASSUMED 90% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	112.47	NA	NA	NA	NA	NA
0.33	111.42	115.10	NA	NA	NA	NA
0.50	*62.78	113.91	117.66	NA	NA	NA
0.67	*35.54	*68.87	116.61	127.35	NA	NA
0.80	NA	*61.98	*75.67	126.76	NA	NA
1.2	NA	NA	*60.08	124.91	133.67	NA
1.67	NA	NA	NA	*80.50	131.81	139.79
3.33	NA	NA	NA	NA	*73.51	*89.94
5.00	NA	NA	NA	NA	NA	*52.86
6.67	NA	NA	NA	NA	NA	NA
85% control	112.77	115.77	118.71	127.44	134.52	141.08

* indicates partial scrubbing

Table 3-8 ANNUAL OPERATION AND MAINTENANCE COSTS IN MILLS/kWh FOR A LIME FGD SYSTEM OR A 500 MW BOILER BASED ON 2 RSD VARIABILITY (ASSUMED 90% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.40	0.60	0.83	1.67	2.50	3.33
0.2	1.86	NA	NA	NA	NA	NA
0.33	1.78	1.97	NA	NA	NA	NA
0.50	*1.08	1.90	2.09	NA	NA	NA
0.67	*0.68	*1.23	2.02	2.67	NA	NA
0.80	NA	*1.08	* 1.40	2.62	NA	NA
1.2	NA	NA	* 1.07	2.47	3.08	NA
1.67	NA	NA	NA	* 1.66	2.91	3.51
3.33	NA	NA	NA	NA	* 1.46	* 2.17
5.00	NA	NA	NA	NA	NA	* 1.18
6.67	NA	NA	NA	NA	NA	NA
85% control	1.89	2.03	2.18	2.72	3.24	3.74

* indicates partial scrubbing.

Table 3-9 ANNUAL FIXED COSTS IN MILLS/kWh FOR A LIME FGD SYSTEM ON A 500 MW BOILER BASED ON 2 RSD VARIABILITY (ASSUMED 90% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.48	NA	NA	NA	NA	NA
0.33	3.44	3.56	NA	NA	NA	NA
0.50	*1.94	3.52	3.64	NA	NA	NA
0.67	*1.10	*2.13	3.60	3.94	NA	NA
0.80	NA	*1.92	*2.34	3.92	NA	NA
1.2	NA	NA	*1.86	3.86	4.13	NA
1.67	NA	NA	NA	*2.49	4.07	4.32
3.33	NA	NA	NA	NA	*2.27	*2.78
5.00	NA	NA	NA	NA	NA	*1.63
6.67	NA	NA	NA	NA	NA	NA
85% control	3.49	3.58	3.67	3.94	4.16	4.36

* indicates partial scrubbing

Table 3-10 ENERGY PENALTY EXPRESSED AS PERCENT OF PLANT ENERGY USAGE FOR A LIME FGD SYSTEM ON 500 MW BOILER BASED ON 2 RSD VARIABILITY (ASSUMED 90% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	5.38	NA	NA	NA	NA	NA
0.33	5.38	5.38	NA	NA	NA	NA
0.50	*2.63	5.38	5.38	NA	NA	NA
0.67	*1.36	*2.89	5.38	5.38	NA	NA
0.80	NA	*2.45	*3.19	5.38	NA	NA
1.2	NA	NA	*2.24	5.38	5.38	NA
1.67	NA	NA	NA	*3.10	5.38	5.38
3.33	NA	NA	NA	NA	*2.45	*3.10
5.00	NA	NA	NA	NA	NA	*1.62
6.67	NA	NA	NA	NA	NA	NA
85% control	5.38	5.38	5.38	5.38	5.38	5.38

* indicates partial scrubbing

Table 3-11 CAPACITY PENALTY EXPRESSED AS PERCENT OF PLANT OUTPUT FOR A LIME FGD SYSTEM ON 500 MW BOILER BASED ON 2 RSD VARIABILITY (ASSUMED 90% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.34	NA	NA	NA	NA	NA
0.33	3.34	3.34	NA	NA	NA	NA
0.50	*1.63	3.34	3.34	NA	NA	NA
0.67	*0.84	*1.79	3.34	3.34	NA	NA
0.80	NA	*1.52	*1.98	3.34	NA	NA
1.2	NA	NA	*1.39	3.34	3.34	NA
1.67	NA	NA	NA	*1.93	3.34	3.34
3.33	NA	NA	NA	NA	*1.52	*1.93
5.00	NA	NA	NA	NA	NA	*1.00
6.67	NA	NA	NA	NA	NA	NA
85% control	3.34	3.34	3.34	3.34	3.34	3.34

* indicates partial scrubbing

Table 3-12 CAPITAL COSTS IN $/kW FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 3 RSD SULFUR VARIABILITY (99.87% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	113.34	NA	NA	NA	NA	NA
0.33	112.33	116.23	NA	NA	NA	NA
0.50	* 67.35	115.11	118.99	NA	NA	NA
0.67	* 39.97	* 72.84	118.00	129.42	NA	NA
0.80	NA	*67.49	* 78.85	128.85	NA	NA
1.2	NA	NA	* 65.88	127.11	136.41	NA
1.67	NA	NA	NA	* 98.71	134.64	143.08
3.33	NA	NA	NA	NA	* 80.77	*110.87
5.00	NA	NA	NA	NA	NA	* 78.99
6.67	NA	NA	NA	NA	NA	NA
85% control	113.56	116.67	119.79	129.17	136.83	143.83

* Indicates partial scrubbing

Table 3-13 ANNUAL OPERATION AND MAINTENANCE COSTS IN MILLS/kWh FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 3 RSD SULFUR VARIABILITY (99.87% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	1.87	NA	NA	NA	NA	NA
0.33	1.79	1.99	NA	NA	NA	NA
0.50	*1.14	1.92	2.11	NA	NA	NA
0.67	*0.73	*1.28	2.04	2.70	NA	NA
0.80	NA	*1.16	*1.44	2.65	NA	NA
1.2	NA	NA	*1.15	2.50	3.12	NA
1.67	NA	NA	NA	* 1.90	2.95	3.56
3.33	NA	NA	NA	NA	*1.22	*2.45
5.00	NA	NA	NA	NA	NA	*1.53
6.67	NA	NA	NA	NA	NA	NA
85% control	1.90	2.04	2.20	2.75	3.27	3.78

* indicates partial scrubbing

Table 3-14 FIXED ANNUAL COSTS IN MILLS/kWh FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 3 RSD SULFUR VARIABILITY (99.87% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.50	NA	NA	NA	NA	NA
0.33	3.46	3.59	NA	NA	NA	NA
0.50	*2.08	3.56	3.68	NA	NA	NA
0.67	*1.23	*2.25	3.64	4.00	NA	NA
0.80	NA	*2.09	*2.44	3.98	NA	NA
1.2	NA	NA	*2.04	3.92	4.21	NA
1.67	NA	NA	NA	*3.05	4.16	4.42
3.33	NA	NA	NA	NA	*2.50	*3.43
5.00	NA	NA	NA	NA	NA	*2.44
6.67	NA	NA	NA	NA	NA	NA
85% control	3.51	3.60	3.70	3.99	4.22	4.44

* indicates partial scrubbing

Table 3-15 ENERGY PENALTY EXPRESSED AS PERCENT OF NET PLANT OUTPUT FOR A LIME FLUE GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 3 RSD SULFUR VARIABILITY (99.87% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	5.38	NA	NA	NA	NA	NA
0.33	5.38	5.38	NA	NA	NA	NA
0.50	*2.89	5.38	5.38	NA	NA	NA
0.67	*1.61	*3.10	5.38	5.38	NA	NA
0.80	NA	* 2.76	*3.36	5.38	NA	NA
1.2	NA	NA	*2.54	5.38	5.38	NA
1.67	NA	NA	NA	*4.15	5.38	5.38
3.33	NA	NA	NA	NA	*2.76	*4.15
5.00	NA	NA	NA	NA	NA	*2.45
6.67	NA	NA	NA	NA	NA	NA
85% control	5.38	5.38	5.38	5.38	5.38	5.38

* indicates partial scrubbing

Table 3-16 CAPACITY PENALTY EXPRESSED AS PERCENT OF NET PLANT OUTPUT FOR A LIME GAS DESULFURIZATION SYSTEM ON A 500 MW BOILER BASED ON 3 RSD SULFUR VARIABILITY (98.87% CONFIDENCE)

Emission limitation, lb $SO_2/10^6$ Btu heat input	Sulfur content of fuel (long term average), lb $S/10^6$ Btu					
	0.4	0.6	0.83	1.67	2.50	3.33
0.2	3.34	NA	NA	NA	NA	NA
0.33	3.34	3.34	NA	NA	NA	NA
0.50	*1.79	3.34	3.34	NA	NA	NA
0.67	*1.00	*1.93	3.34	3.34	NA	NA
0.80	NA	*1.71	*2.09	3.34	NA	NA
1.2	NA	NA	*1.58	3.34	3.34	NA
1.67	NA	NA	NA	*2.57	3.34	3.34
3.33	NA	NA	NA	NA	*1.71	*2.57
5.00	NA	NA	NA	NA	NA	*1.52
6.67	NA	NA	NA	NA	NA	NA
85% control	3.34	3.34	3.34	3.34	3.34	3.34

* indicates partial scrubbing

MINE MOUTH COAL BLENDING COSTS FOR A 600 TON/HR SYSTEM

Coal may be blended at the mine to reduce the fluctuation of sulfur content. This process requires a large capital expenditure for conveyors. Thus the cost per ton of coal is highly sensitive to the basic design of the coal-blending facility.

Capital Costs

A facility suitable for a 1500 MW power plant is estimated herein. Figure 1 shows the basic layout of the system. It is a 600 ton/hr system. The cost of and quantity of equipment required for the system is shown in Table 1. The total purchase price of the equipment is $16 million (1975 dollars). Based on engineering judgement, it is estimated that installation of the equipment will run three times the purchased cost. Thus the direct capital cost of the entire system, installed, is $64 million (1975 dollars). This does not include the cost of the real estate. The indirect costs (contractors fee, engineering, construction money costs, and the like) add an estimated 34 percent to the direct costs. This gives a total capital cost of $86 million sans contingencies. If a 20 percent contingency is added, the total cost of the system approximates $103 million (1975 dollars). Escalating these costs to 1980 based on a 7.5

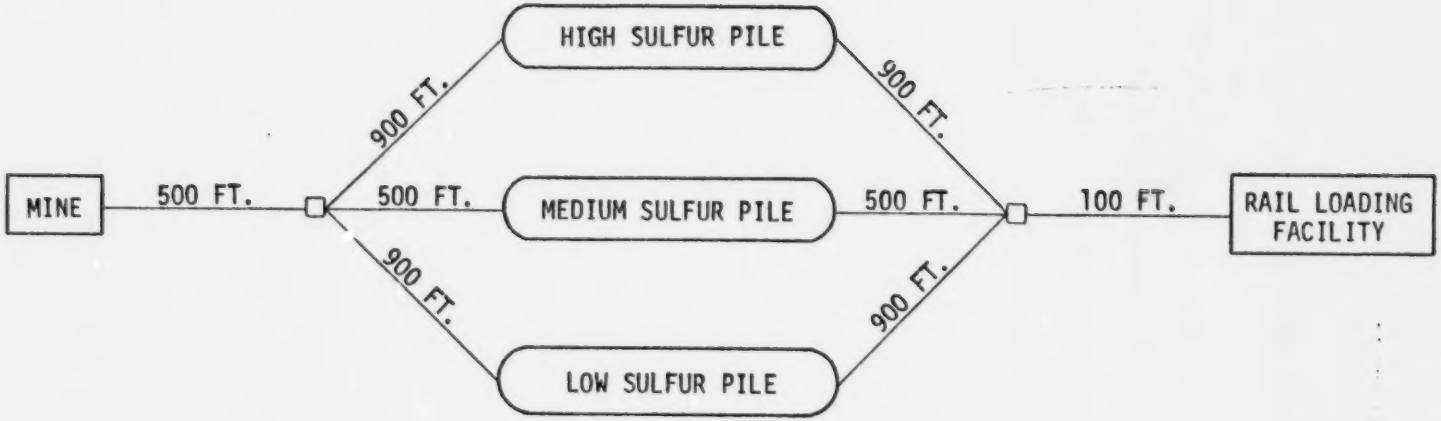

Figure 1. Layout of a 600 ton/hr coal-blending system.

Table 1. PURCHASE PRICE (FOB JOB SITE) OF COAL BLENDING EQUIPMENT FOR A 600 TON/HR SYSTEM[a]

Item	Quantity	Cost (1975 Dollars)[b]
Conveyors	5200 ft	15,200,000
Trippers	6	60,000
200 ton/hr hoppers	3	90,000
Feeders	3	60,000
Mobile equipment	-	440,000
Samplers	-	200,000
Total		16,000,000[b]

[a] Based on PEDCo in-house data. 1975 dollars.

[b] Rounded.

percent compounded annual inflation rate, the total capital cost is $148 million.

Annualized Costs

Annualized costs for a 600 ton/hr coal-blending system can be approximated by assuming the fixed costs are 23 percent of capital costs and the operating and maintenance costs are $0.80 per ton of coal handled. If the system is utilized at 80 percent of capacity, it will handle 4.2 million tons of coal per year. Thus total annualized costs approximate $37.4 million. This adds $8.90 per ton (1980 dollars) to the cost of the coal.

COST OF LIME FGD ON A 500 MW BOILER BURNING

0.52 PERCENT SULFUR COAL (24 HR BASIS)
(0.4 PERCENT ANNUAL)

SO_2 Regulation	0.2 lb $SO_2/10^6$ Btu floor	0.5 lb $SO_2/10^6$ Btu floor
FGD capital cost, $kW	112.47	74.43
Increment over base plant cost ($946/kW),	11.89	7.87
Annualized cost, mills/kWh	6.26	3.85
Increment over base plant cost (25 mills/kWh),	25.04	15.40
Annual SO_2 emissions, TPY	2560	6400
Percent control	75	38
$/ton SO_2 removed	2600	2850